

**TECHNICAL SUPPORT DOCUMENT
FOR
THE PREVENTION OF SIGNIFICANT DETERIORATION
PSD-00-02, AMENDMENT 8
PHILLIPS 66
FERNDALE, WASHINGTON**

September 9, 2015

1. INTRODUCTION

1.1. The Permitting Process

The Prevention of Significant Deterioration (PSD) requirements in Washington State are established in WAC 173-400-700 through 750. These rules require PSD review of all new or modified stationary sources that meet certain overall size and pollution rate criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a new or modified stationary source. The program limits degradation of air quality to that which is not considered “significant” as defined by the regulations listed above. To meet the goal of limiting degradation of air quality, the PSD rules require that an applicant utilize the most effective air pollution control equipment and procedures after considering environmental, economic, and energy factors. The program sets up a mechanism for evaluating and controlling air emissions from a proposed source to minimize the impacts on air quality, visibility, soils, and vegetation.

The location of the facility places it within the jurisdiction of the Northwest Clean Air Agency (NWCAA). The NWCAA is responsible for all air permits with the exception of PSD. The United States Environmental Protection Agency (EPA) gave authority to implement the PSD program in Washington State to the Washington State Department of Ecology (Ecology) as a SIP-approved program effective May 29, 2015.

1.2. The Project

1.2.1. The Site

Phillips 66’s corporate headquarters is located in Houston, Texas. The Ferndale Refinery is located in Whatcom County on an 850-acre site, south and west of Ferndale, Washington. The refinery was built by the General Petroleum Company in 1954 and designed to process low-sulfur, light Canadian crude oil from Alberta delivered by pipeline with an original capacity of 35,000 barrels of crude oil per day. The Ferndale Refinery expanding in 1967, 1972, and 1990. In September 2002 Phillips Refining Company merged with Conoco to become ConocoPhillips, before becoming Phillips 66 in 2012 (as described in Section 1.2.2.1). “Phillips 66” will be used for the remainder of this Technical Support Document (TSD).

The Ferndale Refinery manufactures gasoline (unleaded and super unleaded), kerosene, jet fuel, low-sulfur diesel, propane, heavy fuel oil, and sulfur.

1.2.2. The Proposed Project (Amendment 8)

Phillips 66 submitted an application for Amendment 8 (dated April 23, 2015) that was received on April 28, 2015. Amendment 8 is an administrative amendment that requests additional language changes so that the permit better reflects current operations under the refinery's 2005 federal Clean Air Act based Consent Decree. Several Consent Decree requirements were of a temporary nature to allow the refinery to reach certain compliance goals. Now that those conditions have been satisfied, they are no longer applicable or needed.

Several changes were made to other permit Approval Conditions to improve their clarity. None of these changes reduced the stringency of these conditions.

Since this is an administrative amendment, no public comment period is required.

1.3. PSD Application and History of Previous Amendments

- 1.3.1. The original application was received on April 27, 2000, and found to be complete on August 8, 2000. PSD-00-02 was originally issued on April 4, 2001. The permit was issued for two smaller projects. The Ferndale Upgrade Project involving the installation of a new FCCU with a nominal capacity of 30,000 barrels per day (bpd), and a CO boiler. The new FCCU and CO boiler replaced the previous Thermoform Catalytic Cracking Unit and CO boiler. The gas plant was modified to accommodate the new flow from the FCCU. Finally, a new Alkylation Unit Feed Treater was installed. The Clean Fuels Project involved revamping the existing #2 Hydrofiner to treat light, straight-run gasoline. Additionally, a new Hydrodesulfurizer with a nominal capacity of 14,250 bpd was constructed to treat heavy Fluidized Catalytic Cracking naphtha. Finally, a new Merox Contactor was installed to treat light Fluidized Catalytic Cracking naphtha. These changes allowed the refinery to meet the regulatory requirements for fuel sulfur content.
- 1.3.2. Amendment 1: The permit was amended on June 5, 2002 (PSD-00-02 Amendment 1). The modification permitted the S Zorb process (licensed by Phillips 66 then known as ConocoPhillips) as a replacement for the previously permitted Hydrodesulfurizer. The S Zorb process operates similar to a standard hydrotreater unit using catalyst and similar equipment. Emissions from the S Zorb process remained the same as those listed in the original PSD permit. The unit had a nominal capacity of 17,250 bpd to treat Fluidized Catalytic Cracking naphtha.

In addition to the S Zorb replacement, two heaters (Heavy HCC Gasoline Stripper Reboiler and the Heavy FCC Gasoline HDS Feed Heater) were combined into one heater (Cat Gasoline Desulfurizer Feed Heater). The original heaters were permitted to install Ultra Blue™ Low NO_x burners. The Ultra Blue™ Low NO_x burners had a design capacity of 10 parts per million (ppm) NO_x and combined emissions of 5.1 tons per year (tpy). The Cat Gasoline Desulfurizer Feed Heater has NO_x emissions of 17 ppm and 5.1 tpy. The Cat Gasoline Desulfurizer Feed Heater has the same annual tonnage of NO_x emissions (5.1 tpy) and a lower concentration (one 17 ppm emission point as opposed to two emission points of 10 ppm). Furthermore, emissions of other pollutants were reduced (12.6 tpy CO), 1.1 tpy particulate matter (PM), 4.0 tpy SO₂, and 0.8 tpy volatile organic compounds (VOCs).

Conditions that limited CO emissions were incorrectly removed from the permit during this action. No emission increases were associated with this amendment.

- 1.3.3. Amendment 2 was an administrative amendment that changed the company name and simplified the performance testing requirements in Approval Condition 2. On April 21, 2003, the department was informed that the performance test method specified in Approval Condition 2 limited the source test to one specific testing procedure. The department agreed to change the reference; thus allowing more flexibility in performance testing.
- 1.3.4. Amendment 3 (dated June 14, 2005), was a “major modification” which consisted of the following changes: increased the allowed throughput of the FCCU; added conditions to limit emissions of PM, PM smaller than 10 microns in diameter (PM₁₀); and added conditions to limit CO. The application for Amendment 3 was received on November 18, 2004. Additional information was received on December 22, 2004, and the application was found to be complete on December 23, 2004. Ecology was notified by EPA that EPA satisfied its obligations under the Endangered Species and Magnuson-Stevens Act on April 11, 2005.
 - 1.3.4.1. FCCU: Allowed throughput of the FCCU to increase from a nominal 30,000 bpd to a nominal 35,000 bpd. Emissions of PM₁₀ and CO increased above the PSD Significant Emission Rates (SERs) of 15 and 100 tpy, respectively. Therefore, conditions to limit PM₁₀ and CO were added to the PSD permit.
 - 1.3.4.2. PM and PM₁₀: Although the permit application states that PM will not exceed the PSD SER as a result of the project, the facility has not been able to demonstrate compliance with the PM and PM₁₀ emission limits for the FCCU established in NWCAA’s Order of Approval to Construct (OAC #733a), including those limitations intended to restrict emissions from the project to below the significance levels for PM and PM₁₀, thereby avoiding the requirements of the PSD program for PM and PM₁₀.

- 1.3.4.3. CO: Apparently, Ecology made an error when issuing PSD-00-02 Amendment 1. Conditions to limit CO emissions were removed from the PSD permit and placed into the NOC permit issued by NWCAA. Originally it was the goal of this amendment to return conditions that limit CO into the permit. On February 7, 2005, ConocoPhillips requested Ecology raise the emission limits of CO in the permit. Apparently, ConocoPhillips has had numerous problems complying with the emission limits in the original permit. Today's action will reinstate conditions to limit CO to the PSD permit. During a conference call on February 7, 2005, ConocoPhillips requested Ecology raise the CO emission limits because of difficulty they have had complying with the permitted limits. This information was e-mailed to Ecology on March 15, 2005. As of March 24, 2005, no comments on the proposed CO increase were received from the land managers.

The following paragraph prepared for the PSD-00-02 Amendment 3 TSD, was applicable to Amendment 3 and reflects the name of the facility at that time (ConocoPhillips Company) [Note: Amendment 3 was the last amendment to this permit (PSD-00-02) that was not an administrative change. Amendments 4–7 are administrative revisions]:

“At the time this application was determined to be “complete” (December 23, 2004) the State of Washington had two PSD programs. The federal program, delegated to the Washington State Department of Ecology (Ecology) by the Environmental Protection Agency (EPA) Region X on March 28, 2003 is based upon the March 3, 2003 version of 40 CFR 52.21. The states PSD program (which will be replaced by the new rules on February 10, 2005) is based upon the version of 40 CFR 52.21 that was in effect on July 1, 2000 version of 40 CFR 52.21. Both rules must be complied with for this permit. The federal rule allows a source to use the old rules (state method) for calculating emission increases. The state method is based on future potential emissions minus the past actual emissions. ConocoPhillips has elected to use the state method to evaluate emission increases for the purpose of this permit. What this means is that there is no additional analysis of emissions under the new federal rule required.”

- 1.3.5. Amendment 4 (dated March 16, 2006) was an administrative amendment, extending the compliance date for Approval Condition 7 from December 31, 2006, until June 30, 2007. This compliance date was based upon an EPA Consent Decree. Phillips 66 (then ConocoPhillips) requested this amendment because they had difficulty scheduling the on-site construction of this project.
- 1.3.6. Amendment 5 (dated October 21, 2008) was an administrative amendment. Approval Condition 14 was changed from semi-annual to annual testing, and Approval Condition 21b was changed to submit testing reports within 30 days of

the end of the month. ConocoPhillips (now Phillips 66) requested this amendment because they identified a discrepancy between this approval and the EPA Consent Decree.

- 1.3.7. Amendment 6 (dated August 23, 2011) was an administrative amendment that corrects a mistake in the wording that defines the flexibility of the time period between the annual tests required by existing Approval Conditions 13 and 14. The existing time period wording is incompatible with annual testing periods. There are no changes to the required testing interval or required test methods. ConocoPhillips (now Phillips 66) requested this change in a letter dated May 18, 2011, as a part of their Title V permit renewal process.
- 1.3.8. Amendment 7 (dated August 14, 2014) was an administrative amendment that accomplished the following three changes: it reflected the facility owner's name change from the ConocoPhillips Company to Phillips 66; expanded Condition 2 to include a consent decree short-term NO_x limit of 123.2 ppmvd at zero percent O₂ (7-day rolling average) for the Fluidized Catalytic Cracking Unit (FCCU) and carbon monoxide (CO) boiler; and also expanded Condition 2 to include a consent decree long-term NO_x limit of 96.1 ppmvd at zero percent O₂ (365-day rolling average) for the FCCU and CO boiler.
 - 1.3.8.1. The facility name is now Phillips 66, which reflects the name change from the "ConocoPhillips Company" which occurred in 2012 after corporate restructuring. As described in the application for Amendment 7, "ConocoPhillips Refining & Marketing business and Exploration and Production business were separated into two stand-alone companies. Phillips 66 is now the owner and operator of the Ferndale Refinery." A "change of the owner or operator's business name and/or mailing address" is considered an "administrative revision" per Washington Administrative Code (WAC) 173-400-750(3)(a).
 - 1.3.8.2. Based on Ecology's technical evaluation of the proposal, adding the following NO_x limits, "Does not reduce the stringency of the emission limitation in the PSD permit or the ability of ecology, the permitting authority, EPA, or the public to determine compliance with the approval conditions in the PSD permit." According to WAC) 173-400-750(3)(e), these changes are therefore considered an "administrative revision." The long- and short-term NO_x limits and requirements are based on the following June 3, 2014, EPA determination:¹

¹ From: Phillip Brooks, Director Air Enforcement Division, EPA to: Tim Goedeker, Program Manager, US Consent Decrees, Phillips 66 Company. Re: United States et al. v. ConocoPhillips Co., NO. H-05-258 (S.D. Tex) - Final FCCU NO_x Limits for the Phillips 66 Ferndale Refinery.

1.3.8.3. The new long-term limit will be 96.1 ppmvd NO_x at zero percent O₂ on a 365-day rolling average basis to apply at all times (including during start-up, shutdown, and malfunction) that the FCCU and/or CO boiler are operating.

1.3.8.4. The new short-term limit will be 123.2 ppmvd NO_x at zero percent O₂ on a 7-day rolling average basis, and will exclude periods of start-up, shutdown, and malfunction, but will apply at all other times that the FCCU and/or CO boiler are operating.

1.4. PSD Applicability

- The Phillips 66, Ferndale Refinery, qualifies as a “major source” because it is included in the list of 28-named source categories and has the potential to emit more than 100 tpy of NO_x, CO, SO₂, and VOC.

1.5. New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP)

1.5.1. NSPS apply to certain types of equipment that are newly constructed, modified, or reconstructed after a given applicability date. The applicability of the following NSPS is presented in this section:

- NSPS Subpart Db (Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units)
- NSPS Subpart J (Standards of Performance for Petroleum Refineries)

While there are several other NSPS that apply to this facility, they are not triggered by this permit amendment.

1.5.2. NESHAP

- 40 CFR 63 Subpart UUU - Proposed (National Emission Standards for Petroleum Refineries – Catalytic Cracking, Catalytic Reforming and Sulfur Plant Units)

Subpart UUU is not triggered by this permit amendment.

Although the current amendment is an administrative revision, PSD review details for previous permitting actions (both administrative and other) are included in the following sections to provide background information.

1.6. Emissions and Emissions Control

All emission increases above what the PSD program refers to as “significant” must undergo PSD review. When evaluating emissions against the PSD significance levels, a source’s potential or allowable emissions are used. Potential emissions, or a source’s Potential to Emit (PTE), are based on the theoretical operation 24 hours a day, 365 days per year (8,760 hours) or some other physical limitation of the equipment. In many cases, the number of hours a source would actually operate is lower than its potential emissions. If the source does not anticipate operation at its maximum capacity, it may request a federally enforceable limit on the hours of operation or some other measurable parameter. This limit, if placed in a federally enforceable permit, would result in “allowable” emissions as opposed to potential emissions.

The original application estimated the emissions and throughput of the facility. Originally, it was anticipated that nominal capacity of the FCCU would be 30,000 bpd. Since start-up of the FCCU in April 2003, Phillips 66 has determined that the unit can achieve an output of a nominal 35,000 bpd. An EPA Consent Decree addressed these issues and required Phillips 66 to obtain a PSD permit for PM and PM₁₀ emissions.

1.6.1. Federally Enforceable Limitations

Several of the heaters are not able to reach their full capabilities due to undersized burners. Emissions from those units have been calculated below the units rated potential. The limitations are listed in Appendix A of the permit.

1.7. Netting Analysis

When a facility can show that emissions of a certain pollutant have actually reduced over time, it can use those reductions to “Net” out of PSD review. At the time the original permit was written, two methods of netting were required in Washington State. The federal method used a 5-year contemporaneous period. During the previous five years, all emission increases and decreases are summed and if the resultant is less than significance levels (40 tons for VOCs), that pollutant is not subject to PSD review. The state method utilized a 10-year contemporaneous period. The analysis is the same as the federal method, except for emission reductions older than one year the facility must apply “Emission Reduction Credits” to receive credit for those emissions.

Future potential emissions of VOCs were above the SERs (40 tpy) for this project. Phillips 66, however, applied emission reduction credits from June of 1993 for 1,443 tons of VOC and from April of 1992 for 196 tons of VOC. Phillips 66 also had a reduction in August of 1998 for 1,334.4 tons of VOC. Using the federal 5-year contemporaneous period, the net emission change for the last five years was a negative 1,043.90 tons. Using the 10-year Ecology method, the net emission change is a negative 1,371.90 tons. An evaluation of these methods results in this project not being subject to PSD requirements for VOC emissions.

1.8. Net Emissions Increases

Table 1 identifies the net emission increases associated with this project based upon Amendment 3.

Table 1. Net Emission Increases						
Emission Unit	Net Emission Increase (TPY)					
	PM	PM₁₀	SO₂	NO_x	VOC	CO
Crude Heater (1F-1)	084	0.84	(331.65)	30.81	0.61	9.24
Supplemental Crude Heater (1F-1A)	0.64	0.64	(142.82)	23.55	0.46	7.06
Liquid Feed Heater (4F-1A)	(1.42)	(1.42)	(0.06)	(8.20)	(1.03)	(15.71)
Tar Separator Heater (4-F-2)	1.23	1.23	(293.37)	45.38	0.89	13.62
Alky Depropanizer Reboiler (17F-1)	1.23	1.23	(118.86)	45.43	0.89	13.63
#2 HDF Heater – new LSD (14F-1,2,3)	1.23	1.23	(41.4)	16.75	0.89	13.63
DHT Heater (33F-1)	0.83	0.83	5.51	3.93	0.60	9.18
CGD Feed Heater (Model ID SRC19)	1.31	1.31	4.62	5.10	0.94	14.43
Sulfur Recovery Unit (SRU-19F-21)	0.56	0.56	2.66	5.72	0.43	6.84
#3 Reformer Preheat Heater (18F-1)	0.72	0.72	(0.28)	9.42	0.52	7.91
#3 Reformer Heaters (18F-21,22)	0.66	0.66	(13.08)	8.7	0.48	7.31
#3 Reformer Heaters (18F-23,24)	0.66	0.66	(13.08)	(8.7)	0.48	7.31
#3 Reformer Regen Heater (18F-26)	0.01	0.01	(5.15)	0.13	0.01	0.11
#1 Boiler (22F-1C)	3.71	3.71	(57.67)	25.44	2.68	41.01
Combustion Air Heater on FCC	N/A	N/A	N/A	N/A	0.005	N/A
FCC/COB Emissions (Model ID SRC21)	63.51	63.51	548.4	308.1	26.07	203.9
Old CO Boiler (4F-7)	(0.78)	(0.78)	(49.97)	(10.25)	(0.56)	(7.13)
TCC Surge Separator Vent (4D-3)	(64.8)	(45.4)	(920.5)	(19.1)	0	0
Storage Tanks	0	0	0	0	37.19	0
Product Loading	0	0	0	0	211.52	0
Equipment Fugitives	0	0	0	0	7.39	0
Project Emission Increase	10.14	29.54	(1426.69)	499.63	290.5	332.4
Creditable Decrease (EPA Method)	N/A	N/A	N/A	N/A	(1334.4)	N/A
Creditable Decrease (Ecology Method)	N/A	N/A	N/A	N/A	(1362.4)	N/A
Net Emissions Increase (EPA Method)	10.14	29.54	(1426.69)	499.63	(1043.90)	332.4
Net Emissions Increase (Ecology Method)	10.14	29.54	(1426.69)	499.63	(1371.90)	332.4

1.8.1. PM and PM₁₀

Historically, the state of Washington has measured particulate in the form of total suspended particulate. Total suspended particulate and particulate matter are interchangeable terms and for the remainder of this fact sheet, the term particulate matter will be used. PM₁₀ is a subset of particulate matter and is composed of particles that are smaller than 10 microns in diameter.

Emission Unit	April 26, 2000 PM (TPY)	Nov. 18, 2004 PM (TPY)	Difference 2004-2000 PM (TPY)	April 26, 2000 PM ₁₀ (TPY)	Nov. 18, 2004 PM ₁₀ (TPY)	Difference 2004-2000 PM ₁₀ (TPY)
Crude Heater (1F-1)	0.8	0.8	---	0.8	0.8	---
Supplemental Crude Heater (1F-1A)	0.6	0.6	---	0.6	0.6	---
Liquid Feed Heater (4F-1A)	(1.4)	(1.4)	---	(1.4)	(1.4)	---
Tar Separator Heater (4-F-2)	1.2	1.2	---	1.2	1.2	---
Alky Depropanizer Reboiler (17F-1)	1.2	1.2	---	1.2	1.2	---
#2 HDF Heater – new LSD (14F-1,2,3)	1.2	1.2	---	1.2	1.2	---
DHT Heater (33F-1)	0.8	0.8	---	0.8	0.8	---
HCG HDS Feed Heater ¹	1.3	---	(1.3)	1.3	---	(1.3)
HCC HDS Stripper Reboiler ¹	1.1	---	(1.1)	1.1	---	(1.1)
CGD Feed Heater (Model ID SRC19) ¹	---	1.3	1.3	---	1.3	1.3
Sulfur Recovery Unit (SRU-19F-21)	0.6	0.6	---	0.6	0.6	---
#3 Reformer Preheat Heater (18F-1)	0.7	0.7	---	0.7	0.7	---
#3 Reformer Heaters (18F-21,22)	0.7	0.7	---	0.7	0.7	---
#3 Reformer Heaters (18F-23,24)	0.7	0.7	---	0.7	0.7	---
#3 Reformer Regen Heater (18F-26)	0.01	0.01	---	0.01	0.01	---
#1 Boiler (22F-1C)	3.7	3.7	---	3.7	3.7	---
Combustion Air Heater on FCC ²	---	---	---	N/A	---	---
FCC Emissions ²	75.1	---	(75.1)	46.9	---	(46.9)
New CO Boiler Aux fuel firing ²	---	---	---	N/A	---	---
FCC/COB Emissions (Model ID SRC21) ²	---	63.5	63.5	---	63.5	63.5
Old CO Boiler (4F-7)	(0.8)	(0.8)	---	(0.8)	(0.8)	---
TCC Surge Separator Vent (4D-3)	(64.8)	(64.8)	---	(45.4)	(45.4)	---
Storage Tanks	0	0		0	0	---
Product Loading	0	0		0	0	---
Equipment Fugitives	0	0		0	0	---
Project Emission Increase	22.7	10.0	(12.7)	13.91	29.4	15.5

¹ PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater.

² This is actually the same equipment accounted for differently.

Total projected emissions of PM are 10 tpy. Amendment 3 results in a 12.7 tpy decrease over the original permitted limits PM. EPA and the NWCAA requested Ecology include a PM limit in Amendment 3. While PM is not technically subject to PSD review, an enforceable limit will be placed in the permit.

Total projected emissions of PM₁₀ are 29.54 tpy. Amendment 3 resulted in a 15.52 tpy increase over the original PM₁₀ permitted limits.

1.8.2. Sulfur Oxides

During the combustion of fossil fuels, sulfur contained in the fuel is released into the atmosphere as sulfur oxides. This sulfur is converted into compounds that are responsible, in part, for acid rain. The air can absorb some sulfur without causing a measurable increase in the sulfur in the air. Nevertheless, regulatory agencies are required to keep these emissions below thresholds that cause harm to the environment and to human health. Table 3 is a comparison of the net emissions increase from the original permit SO_x emissions compared to Amendment 3.

Table 3. SO_x Emissions			
Emission Unit	April 26, 2000 SO_x (TPY)	Nov. 18, 2004 SO_x (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	(331.6)	(331.6)	---
Supplemental Crude Heater (1F-1A)	(142.8)	(142.8)	---
Liquid Feed Heater (4F-1A)	(0.06)	(0.06)	---
Tar Separator Heater (4-F-2)	(293.3)	(293.3)	---
Alky Depropanizer Reboiler (17F-1)	(118.8)	(118.8)	---
#2 HDF Heater – new LSD (14F-1,2,3)	(41.4)	(41.4)	---
DHT Heater (33F-1)	5.5	5.5	---
HCG HDS Feed Heater ¹	4.6	---	(4.6)
HCC HDS Stripper Reboiler ¹	4.0	---	(4.0)
CGD Feed Heater (Model ID SRC19) ¹	---	4.6	4.6
Sulfur Recovery Unit (SRU-19F-21)	2.7	2.7	---
#3 Reformer Preheat Heater (18F-1)	(0.3)	(0.3)	---
#3 Reformer Heaters (18F-21,22)	(13.1)	(13.1)	---
#3 Reformer Heaters (18F-23,24)	(13.1)	(13.1)	---
#3 Reformer Regen Heater (18F-26)	(5.1)	(5.1)	---
#1 Boiler (22F-1C)	(57.7)	(57.7)	---
Combustion Air Heater on FCC ²	0.2	N/A	(0.2)
FCC Emissions ²	547.7	---	(547.7)
New CO Boiler Aux fuel firing ²	0.8	---	(0.8)

Table 3. SO_x Emissions			
Emission Unit	April 26, 2000 SO_x (TPY)	Nov. 18, 2004 SO_x (TPY)	Difference 2004-2000 (TPY)
FCC/COB Emissions (Model ID SRC21) ²	---	548.4	548.4
Old CO Boiler (4F-7)	(50)	(50)	---
TCC Surge Separator Vent (4D-3)	(920.5)	(920.5)	---
Storage Tanks	0	0	---
Product Loading	0	0	---
Equipment Fugitives	0	0	---
Project Emission Increase	(1422.26)	(1426.69)	(4.4)
¹ PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater.			
² This is actually the same equipment accounted for differently.			

The emission units that will have a change in SO_x are shown in Table 3. Emissions of SO_x (-1426.69 tpy) are lower than the PSD SER (40 tpy) and the change between the original permit and Amendment 3 is a 4.4 tpy reduction in SO_x emissions. Therefore, SO_x was not subject to PSD review in Amendment 3.

1.8.3. Nitrogen Oxides

During the combustion of fossil fuels, nitrogen oxides are released into the atmosphere. This nitrogen, in the form of NO_x, is converted into compounds that are partly responsible for smog. Even though air, made up of approximately 79 percent nitrogen, the remainder being oxygen and trace amounts of other compounds, can absorb some additional nitrogen oxides without causing a measurable increase in smog. Sources that emit NO_x are required to keep these emissions below thresholds that cause harm to the environment and human health.

NO_x emissions are normally generated by the oxidation of nitrogen in the fuel (fuel-bound nitrogen) or nitrogen in the combustion air (thermal NO_x). Table 4 is a comparison of the net emissions increase from the original permit NO_x emissions compared to Amendment 3 emissions.

Table 4. NO_x Emissions			
Emission Unit	April 26, 2000 NO_x (TPY)	Nov. 18, 2004 NO_x (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	30.8	30.8	---
Supplemental Crude Heater (1F-1A)	23.5	23.5	---

Table 4. NO_x Emissions			
Emission Unit	April 26, 2000 NO_x (TPY)	Nov. 18, 2004 NO_x (TPY)	Difference 2004-2000 (TPY)
Liquid Feed Heater (4F-1A)	(8.2)	(8.2)	---
Tar Separator Heater (4-F-2)	45.4	45.4	---
Alky Depropanizer Reboiler (17F-1)	45.4	45.4	---
#2 HDF Heater – new LSD (14F-1,2,3)	16.7	16.7	---
DHT Heater (33F-1)	3.9	3.9	---
HCG HDS Feed Heater ¹	7.0	---	(7.0)
HCC HDS Stripper Reboiler ¹	6.1	---	(6.1)
CGD Feed Heater (Model ID SRC19) ¹	---	5.1	5.1
Sulfur Recovery Unit (SRU-19F-21)	5.7	5.7	---
#3 Reformer Preheat Heater (18F-1)	9.4	9.4	---
#3 Reformer Heaters (18F-21,22)	8.7	8.7	---
#3 Reformer Heaters (18F-23,24)	8.7	8.7	---
#3 Reformer Regen Heater (18F-26)	0.1	0.1	---
#1 Boiler (22F-1C)	25.4	25.4	---
Combustion Air Heater on FCC ²	0.8	---	(0.8)
FCC Emissions ²	463.1	---	(463.1)
New CO Boiler Aux fuel firing ²	30.2	---	(30.2)
FCC/COB Emissions (Model ID SRC21) ²	---	308.1	308.1
Old CO Boiler (4F-7)	(10.2)	(10.25)	---
TCC Surge Separator Vent (4D-3)	(19.1)	(19.1)	---
Storage Tanks	0	0	---
Product Loading	0	0	---
Equipment Fugitives	0	0	---
Project Emission Increase	693.4	499.63	(193.8)
¹ PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater.			
² This is actually the same equipment accounted for differently.			

The emission units that will have a change in NO_x are shown in Table 4. Emissions of NO_x (499.63 tpy) are higher than the PSD SER (40 tpy) but less than those in the original permit (693.4 tpy). There were no proposed changes in the permit limits for NO_x in Amendment 3.

1.8.4. VOCs

VOCs have the potential to cause or contribute to ozone levels that violate the national ambient air quality standards for ozone. Ozone is a major component of smog which causes adverse health and environmental impacts when present in sufficiently high concentrations at ground level. Table 5 is a comparison of the net emissions increase from the original permit VOC emissions to Amendment 3 emissions.

Table 5. VOC Emissions			
Emission Unit	April 26, 2000 VOC (TPY)	Nov. 18, 2004 VOC (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	0.6	0.61	---
Supplemental Crude Heater (1F-1A)	0.5	0.5	---
Liquid Feed Heater (4F-1A)	(1.0)	(1.0)	---
Tar Separator Heater (4-F-2)	0.9	0.9	---
Alky Depropanizer Reboiler (17F-1)	0.9	0.89	---
#2 HDF Heater – new LSD (14F-1,2,3)	0.9	0.89	---
DHT Heater (33F-1)	0.6	0.6	---
HCG HDS Feed Heater ¹	0.9		(0.9)
HCC HDS Stripper Reboiler ¹	0.8		(0.8)
CGD Feed Heater (Model ID SRC19) ¹	---	0.9	0.9
Sulfur Recovery Unit (SRU-19F-21)	0.4	0.4	---
#3 Reformer Preheat Heater (18F-1)	0.5	0.5	---
#3 Reformer Heaters (18F-21,22)	0.5	0.5	---
#3 Reformer Heaters (18F-23,24)	0.5	0.5	---
#3 Reformer Regen Heater (18F-26)	0.01	0.01	---
#1 Boiler (22F-1C)	2.7	2.7	---
Combustion Air Heater on FCC ²	0.05	0.05	---
FCC Emissions ²	20.1	---	(20.1)
New CO Boiler Aux fuel firing ²	1.6	---	(1.6)
FCC/COB Emissions (Model ID SRC21) ²	---	26.1	26.1
Old CO Boiler (4F-7)	(0.6)	(0.6)	---
TCC Surge Separator Vent (4D-3)	0	0	---
Storage Tanks	21.8	37.2	15.4
Product Loading	124.2	211.5	87.3
Equipment Fugitives	7.4	7.4	---
Project Emission Increase	184.3	290.5	106.3
Net Emissions Increase (EPA Method)	(1,150.1)	(1,043.9)	
Net Emissions Increase (Ecology Method)	(1178.1)	(1,071.9)	
¹ PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater.			
² This is actually the same equipment accounted for differently.			

The emission units with VOC emission changes resulting from Amendment 3 are shown in Table 6. Emissions of VOCs (290.5 tpy) are higher than the PSD SER (40 tpy). However, looking back to the netting analysis performed in 2000, the project resulted in greater than 1,000 tons of VOC credits being unused. This reduction greatly improved the air quality in the vicinity of the Ferndale Refinery. Had it not been for the error made by Phillips 66 of underestimating the throughput capacity of the FCCU, VOC emissions would not be discussed here. Ecology has determined that since Amendment 3 was a correction to a permit that had already been issued, it was appropriate to look back at the original netting analysis and calculate the increase in VOC emissions based upon the April 2000 numbers. VOCs were therefore not subject to PSD review in Amendment 3.

1.8.5. CO

CO is a colorless, odorless, and at high levels, a poisonous gas, formed when carbon in fuel is not burned completely. It is a component of motor vehicle exhaust, which contributes about 60 percent of all CO emissions nationwide. High concentrations of CO generally occur in areas with heavy traffic congestion. In cities, as much as 95 percent of all CO emissions may come from automobile exhaust. Other sources of CO emissions include industrial processes, non-transportation fuel combustion, and natural sources such as wildfires. Peak CO concentrations typically occur during the colder months of the year when CO automotive emissions are greater and nighttime inversion conditions (where air pollutants are trapped near the ground beneath a layer of warm air) are more frequent. CO enters the bloodstream through the lungs, and reduces oxygen delivery to the body's organs and tissues. Visual impairment, reduced work capacity, reduced manual dexterity, poor learning ability, and difficulty in performing complex tasks are all effects associated with exposure to elevated CO levels.

Table 6 is a comparison of the net emissions increase from the original permit CO emissions compared to Amendment 3 emissions.

Table 6. CO Emissions			
Emission Unit	April 26, 2000 CO (TPY)	Nov. 18, 2004 CO (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	9.2	9.2	---
Supplemental Crude Heater (1F-1A)	7.1	7.1	---
Liquid Feed Heater (4F-1A)	(15.7)	(15.7)	---
Tar Separator Heater (4-F-2)	13.6	13.6	---
Alky Depropanizer Reboiler (17F-1)	13.6	13.6	---
#2 HDF Heater – new LSD (14F-1,2,3)	13.6	13.6	---
DHT Heater (33F-1)	9.2	9.2	---
HCG HDS Feed Heater ¹	14.4	---	(14.4)
HCC HDS Stripper Reboiler ¹	12.6	---	(12.6)

Table 6. CO Emissions			
Emission Unit	April 26, 2000 CO (TPY)	Nov. 18, 2004 CO (TPY)	Difference 2004-2000 (TPY)
CGD Feed Heater (Model ID SRC19) ¹	---	14.4	14.4
Sulfur Recovery Unit (SRU-19F-21)	6.8	6.8	---
#3 Reformer Preheat Heater (18F-1)	7.9	7.9	---
#3 Reformer Heaters (18F-21,22)	7.3	7.3	---
#3 Reformer Heaters (18F-23,24)	7.3	7.3	---
#3 Reformer Regen Heater (18F-26)	0.1	0.1	---
#1 Boiler (22F-1C)	41.0	41.0	---
Combustion Air Heater on FCC ²	0.7	N/A	(0.7)
FCC Emissions ²	42.3	---	(42.3)
New CO Boiler Aux fuel firing ²	24.9	---	(24.9)
FCC/COB Emissions (Model ID SRC21) ²	---	203.9	203.9
Old CO Boiler (4F-7)	(7.1)	(7.1)	---
TCC Surge Separator Vent (4D-3)	(0)	0	---
Storage Tanks	0	0	---
Product Loading	0	0	---
Equipment Fugitives	0	0	---
Project Emission Increase	209.0	332.4	123.4
¹ PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater. ² This is actually the same equipment accounted for differently.			

The emission units that had an increase in CO (for Amendment 3) are shown in Table 6. The emissions increase of CO (332.4 tpy) is greater than the PSD SER (100 tpy) and the original permit (209.0 tpy). As per Consent Decree, ConocoPhillips will comply with revised emissions limits for CO.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1. Definitions

Best Available Control Technology (BACT) is defined as an emission limitation based on the most stringent level of emission control applied at a similar source that is technically and economically feasible.

In a BACT analysis, the applicant must rank all control options from highest level of control to the lowest. If the applicant can show that the highest level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is evaluated. Ultimately, the burden of proof is on the applicant to prove why the most stringent level of control should not be used.

2.2. Regulatory Requirements

An applicant is required by federal law to use BACT for any pollutant that will have a significant emission increase at any PSD source. An applicant is required by Washington State regulations to use BACT for any pollutant that will have increased emissions, provided that the emission unit was physically modified.

If a project is proposed in an area that exceeds ambient air quality standards for a pollutant, the proposed source must use a control technology that will result in the lowest achievable emission rate (LAER) for that pollutant. Additionally, the applicant would be required to reduce emissions from other sources in the area at least as much as the proposed source will increase emissions. However, the site of the Amendment 3 modification is in an area which has been designated as in attainment with national and state ambient air quality standards for PM/PM₁₀, NO_x, CO, and VOC. Therefore, the facility is not required to install LAER.

2.3. Clearinghouse Control Technology Review

There was no new clearinghouse review performed for PM₁₀ emissions. After a quick review of the clearinghouse, Ecology believes that the review performed for the original PSD application (April 4, 2001) is sufficient to satisfy the requirements for clearinghouse review. For CO emissions, Phillips 66 submitted information shown in Table 7. (The following BACT section was performed for Amendment 3 but is included in this updated TSD to provide background information.)

Table 7. CO Clearinghouse Results

Permit Date	RBL ID	Facility Name	Process Name	Short-Term Limit (ppmdv @ 0% O₂)	Long-Term Limit (ppmdv @ 0% O₂)	Control Method
4/3/2002	TN-0153	Williams Refining & Marketing, LLC	FCCU	300	50	(N)
8/18/2004	OK-0102	Ponca City Refinery	FCCU, (2)	500	150	(FCCU-CO COMBUSTION PROMOTER)
6/10/2002	TX-0379	ExxonMobil Beaumont Refinery	FCCU CO BOILER STACK (PRESCRUBBER)	500	N/A	(N) NONE INDICATED
6/10/2002	TX-0379	ExxonMobil Beaumont Refinery	FCCU SCRUBBER STACK	500	500	(N) NONE INDICATED

Table 7. CO Clearinghouse Results

Permit Date	RBLC ID	Facility Name	Process Name	Short-Term Limit (ppmdv @ 0% O₂)	Long-Term Limit (ppmdv @ 0% O₂)	Control Method
10/5/2001	TX-0346	West Refinery	(FCCU)	500	500	(B) MIX WITH NAT GAS AND INCINERATE IN CO BOILER
5/23/2001	TX-0359	Limestone Electric Generating Station	FLUIDIZED-BED CATALYTIC CRACKING UNIT (FCCU)	500	100	(P) USE OF FULL COMBUSTION
2/23/2000	TX-0429	Valero Refining Co. – Texas City	FCCU	500	500	(A) CO BOILER
5/11/2001	AR-0061	Lion Oil Co. Refinery, El Dorado	FLUIDIZED-BED CATALYTIC CRACKING UNIT (FCCU)	500	100	(P) USE OF FULL COMBUSTION
12/14/1990	VI-0003	Hess Oil Virgin Island Corp. – Hovic	FCC UNITS, 2	649.6	432	(P) COMBUSTION CONTROL & HIGH TEMP REGENERATOR
1/13/2003	OK-0092	Valero Ardmore Refinery	FCCU Regenerator No. 1	N/A	N/A	(P) CO BOILER AND INCINERATOR
1/13/2003	OK-0092	Valero Ardmore Refinery	FCCU REGENERATOR NO. 2	N/A	N/A	(P) HIGH TEMPERATURE REGENERATION
2/10/1995	LA-0090	TransAmerican Refining Corp.	REGENERATOR, FCCU	N/A	N/A	(B) CO BOILER OR HIGH TEMP REGENERATION
1/15/1993	LA-0085	TransAmerican Refining Corp.	REGENERATOR, FCCU (NO.1)	N/A	N/A	(A) CO BOILER
1/15/1993	LA-0085	TransAmerican Refining Corp.	CATALYTIC CRACKING FCCU REGENERATOR	N/A	N/A	(A) CO BOILER
6/14/1991	LA-0078	Murphy Oil USA, Inc.	FCCU (FLUID CATALYTIC CRACKING UNIT)	N/A	N/A	(A) HIGH TEMP REGENERATOR AT >1300 DEGREES F
6/9/2003	OK-0089	TPI Petroleum Inc., Valero Ardmore Refinery	REGENERATOR & THERMAL OXIDATION SYSTEM, FCCU NO. 1	N/A	N/A	(A) CO BOILER AND INCINERATOR
6/9/2003	OK-0089	TPI Petroleum Inc., Valero Ardmore Refinery	REGENERATOR, FCCU NO. 2	N/A	N/A	(P) HIGH TEMPERATURE REGENERATION

2.4. BACT for PM and PM₁₀

The following technologies were considered for controlling PM/PM₁₀ emissions from the FCCU in the April 20, 2000, permit application as shown in Table 8.

Table 8. BACT Analysis for PM₁₀			
Technology	Effectiveness	Technically Feasible?	Selected as BACT?
Baghouse	>99%	No	No
Electrostatic Precipitator	0.10 lb/1,000 lb Coke Burned	Yes	No
Wet Gas Scrubber	0.50 lb/1,000 lb Coke Burned¹	Yes	Yes
Cyclone	< 30%	Yes	No
¹ As per Consent Decree, 0.8 lb/1,000 lb will be the emission standard between January 27, 2005, and the date that COPC demonstrates compliance with the 0.50 lb/1000 lb coke burned, but no later than June 30, 2007.			

2.4.1. Baghouse

Baghouses cannot operate in moist environments due to filter binding. The regenerator flue gas leaves the heat recovery unit between 600° and 750°F. The maximum operating temperature for economical, commercially available filter media is 500°F. Baghouse operating temperatures in excess of filter maximum operating temperatures create the potential for explosion or fire. For these reasons, the applicant proposed that the baghouse was technically infeasible for controlling PM/PM₁₀ emissions from the FCC regenerator. Ecology agrees that a baghouse would be technically infeasible.

2.4.2. Electrostatic Precipitator

Electrostatic Precipitators (ESPs) have long been used for the control of PM/PM₁₀ from FCC regenerator effluents. An ESP designed to achieve 95 percent PM/PM₁₀ control was evaluated for BACT. The applicant stated that the cost associated with this technology was excessive. Those cost numbers were not available to the author of this document at the time this document was prepared. However, because the wet gas scrubber is already in place and the increase in PM/PM₁₀ emissions associated with this modification is only 29 tpy, Ecology agrees that an electrostatic precipitator for controlling PM/PM₁₀ emissions is not BACT for this project.

2.4.3. Wet Gas Scrubber

A wet gas scrubber was proposed by the applicant for controlling SO₂ emissions. It is also the next technology with the next highest removal efficiency in the top down evaluation for PM/PM₁₀ control. It is capable of achieving 0.8 lb PM/PM₁₀ per 1,000 lb coke burn off and 0.50 lb PM/PM₁₀ per 1,000 lb of coke burned. The applicant estimated the cost per ton of PM/PM₁₀

remove to be \$13,402. While this figure generally exceeds the cost threshold Ecology used for economic viability, Ecology agrees that a wet gas scrubber satisfies BACT for the control of PM/PM₁₀ emissions from the FCC regenerator.

2.4.4. Cyclones

Cyclones have the lowest control efficiency of all of the identified technologies. As particle size decreases, so does efficiency. Cyclones have difficulty removing particles of 30 microns or smaller. Cyclones are already employed to separate the catalyst from the gas stream prior to the wet gas scrubber. Particulate emissions from a wet gas scrubber typically have a particle diameter of less than 10 microns. The applicant determined the use of cyclones to be technically infeasible for controlling emissions of PM/PM₁₀ from the FCC regenerator.

While Ecology does not agree that cyclones are technically infeasible, we do agree that the removal efficiency would be extremely low and therefore the wet gas scrubber was selected as BACT above.

2.5. BACT for CO

The following technologies were considered for controlling CO emissions from the FCCU in the April 20, 2000, permit application as shown in Table 9.

Table 9. BACT Analysis for CO			
Technology	Effectiveness	Technically Feasible?	Selected as BACT?
High temperature regeneration	50–500 ppm	No	No
Thermal oxidation	50–500 ppm	Yes	Yes
Catalytic oxidation	50–500 ppm	No	No
CO combustion promoter	500 ppm	Yes	No

2.5.1. High Temperature Regeneration

High temperature regeneration or full combustion regeneration uses excess oxygen and high operating temperatures, 1,300° to 1,400°F, to reduce carbon deposits, or coke, on FCC catalyst and to complete the conversion of CO to carbon dioxide (CO₂). This operating method is sometimes used in conjunction with CO combustion promoter. Phillips 66 FCC can operate at both full and partial combustion scenarios. In partial combustion mode, the regenerator does not continuously supply fuel and excess oxygen. It would therefore be impossible to achieve the high operating temperature of the full combustion mode to reduce carbon deposits on the FCC catalyst and complete the combustion of CO to CO₂ when operating in the partial combustion mode. Phillips 66 has determined that the use of high temperature regeneration to control the emissions of CO from the FCC is technically infeasible because it would only work part of the

time. Ecology agrees that high temperature regeneration for controlling CO emissions from the FCC is technically infeasible and is not evaluated further.

2.5.2. Thermal Oxidation

Thermal oxidation uses the concepts of temperature, time, and turbulence to achieve complete combustion. The combustion process is thought of as occurring in two separate stages: (1) the combustion of fuels and (2) the combustion of pollutants. Use of a thermal oxidizer is equivalent to adding a combustion chamber where the regenerator vent gas is heated above its ignition temperature. Excess oxygen and additional fuel are supplied to reach this higher temperature and complete the conversion of CO to CO₂.

The most common type of thermal oxidizer currently used to control CO emissions from a partial burn FCC regenerator is a CO boiler. CO boilers typically operate at approximately 1,800°F to ensure complete conversion. Phillips 66 currently operates a CO boiler as part of the existing FCC system.

Partial burn FCC regenerators operate at or below 1,250°F. The lower operating temperatures result in regenerator vent gas CO concentrations well in excess of 500 ppm_{dv}. Once the vent gases pass through a CO boiler, CO concentrations are between 50 and 500 ppm_{dv}, comparable to high temperature regeneration FCC effluents. For refiners operating high temperature regeneration FCCs, a CO boiler is not necessary because effluent CO concentrations are already less than 500 ppm_{dv}.

The FCC at the Ferndale Refinery will be designed to operate under both full and partial combustion scenarios. Refineries that operate partial combustion FCCs use CO boilers to control CO emissions. Refineries operating FCCs exclusively in a full combustion mode, also known as high temperature regeneration, do not require the use of a CO boiler. Partial combustion regeneration followed by a CO boiler achieves comparable results to high temperature regeneration. CO boilers are typically used to control regenerator effluents with CO concentrations in excess of 1,000 ppm_{dv}. Therefore, a CO boiler is necessary to control CO emissions from this process. The RBLC database has identified CO Boilers as BACT for partial combustion FCCs.

Phillips 66 proposed thermal oxidation to be BACT for controlling CO emissions from the FCC. Ecology agrees that the use of a CO boiler is BACT for controlling CO emissions from the FCC.

2.5.3. Catalytic Oxidation

Catalytic oxidizers are an alternative to thermal oxidizers. A solid catalyst is used to create a heterogeneous reaction. A catalyst is an element or compound that speeds up a reaction without undergoing change itself. The catalyst allows complete oxidation to take place at a faster rate and at a lower temperature than is capable by thermal oxidation.

In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at 650°F to 1,000°F. Approximately 1.5 to 2.0 ft³ of catalyst is required per 1,000 standard ft³ per minute gas flow rate (waste gas plus supplementary fuel combustion products).

The main problem in catalytic oxidizers is the loss of catalyst activity. They cannot be used on waste gas streams containing significant amounts of particulate matter. Particulate deposits foul the catalyst and prohibit oxidation. High temperatures also accelerate catalyst deactivation. Even short-term temperatures above 1,500°F can cause almost total loss of catalyst activity.

Phillips 66 has proposed that the use of catalytic oxidation to control the emissions of CO from the FCC is technically infeasible. Ecology agrees that catalytic oxidation for controlling CO emissions from the FCC is technically infeasible and is not evaluated further.

2.5.4. CO Combustion Promoter

Complete oxidation of CO to CO₂ takes place in an ideally designed and operated regenerator. However, since ideal conditions cannot always be reached and maintained during industrial operation, some petroleum refiners use a CO combustion promoter. The promoter is a platinum and/or palladium catalyst that is injected into full combustion regenerators only as needed to ensure that CO concentrations remain below 500 ppm_{dv}.

While use of a CO combustion promoter can lower the CO content of the flue gas, it also has some drawbacks. Promoter is frequently added to the regenerator two to three times per day at a rate of 3 to 5 pounds per ton (lb/ton) of fresh FCC catalyst. The promoter increases the requirement for combustion air and raises the regenerator temperature thus, increasing thermal deactivation of the catalyst. It is also important to verify the metallurgy in the regenerator is designed to accommodate higher temperature operation.

Catalytic oxidation is able to achieve a greater reduction in CO emissions. Therefore, the CO combustion promoter is not considered further.

3. AMBIENT AIR QUALITY ANALYSIS

3.1. Impact Assessment

This section addresses changes from Amendment 3 only (Amendments 4–8 are administrative revisions that do not alter the results of this section).

PSD rules require an assessment of ambient air quality impacts from any new or modified major facility emitting pollutants in significant quantities. Limiting increases in ambient concentrations to the maximum allowable increments prevents significant deterioration of air quality.

An air quality analysis can include up to three parts: Significant Impact analysis, National Ambient Air Quality Standards (NAAQS) analysis, and PSD Increment analysis. The first step in the air quality analysis is to determine if emissions from the proposed project result in impacts greater than the modeling significance levels (MSLs). Then, for those pollutants and averaging periods that have impacts greater than the MSL, a NAAQS analysis is used to determine if the proposed project will cause or contribute to an exceedance of a NAAQS. The PSD Increment analysis is used to determine if the change in the air quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

This section will discuss the air quality impact analysis of the nearby Class II area. The air quality impact analysis for the Class I areas will be discussed along with the Air Quality Related Values (AQRVs) in Chapter 4.

Table 10 is a comparison of the proposed projects maximum-modeled pollutant concentrations, to the PSD programs Class II modeling Significant Impact Levels (SILs) and monitoring de minimis levels. If the maximum projects modeled emissions exceed the de minimis levels additional preconstruction ambient monitoring may be required.

Table 10. Comparison of the Maximum Modeled Pollutant Concentrations to the SILs and de Minimis Levels				
Pollutant	Averaging Period	Monitoring de Minimis Level (µg/m³)	Modeling SIL (µg/m³)	Maximum Concentration (µg/m³)
PM ₁₀	Annual	---	1	0.50
	24-hour	10	5	3.74
CO	1-hour	---	2,000	845.35
	8-hour	575	500	447.30

The predicted ambient impacts from emissions of PM₁₀ and CO do not exceed the monitoring de minimis levels. Ecology has determined that this data is adequate to determine that no preconstruction monitoring will be required as shown in Table 10.

Emissions of PM₁₀ and CO are also below the modeling SILs. Therefore, further modeling for cumulative impact and increment analyses is not required.

3.2. Toxic Air Pollutants

There is no toxic pollutant increases associated with this project. An analysis of toxic air pollutants was performed by NWCAA.

4. AQRVs

This section addresses changes from Amendment 3 only (Amendments 4–8 are administrative revisions that do not alter the results of this section).

CO is not a Class I pollutant of concern because CO does not impact visibility or deposition and an increment analysis is not required. Therefore, the remainder of this section addresses emissions of PM₁₀.

In order to show that the increase in PM₁₀ emissions did not impact a Class I area, an ISC-PRIME model was run for the nearest Class I area (North Cascade National Park). Table 11 compares the modeling results with the Class I MSLs for PSD increment. The concentration shown represents the highest modeled concentration.

Table 11. Comparison of the Maximum Modeled Pollutant Concentrations to the Class I Area SILs					
Pollutant	Averaging Period	Modeling Results (ug/m³)	Class I Area SILs		PSD Class I Area Increment (ug/m³)
			EPA Proposed (ug/m³)	FLM Recommended (ug/m³)	
PM ₁₀	24-hour	0.0352	0.3	0.27	8
	Annual	0.0028	0.2	0.08	4

4.1. Impacts on Visibility

Because the maximum PM₁₀ concentrations are below the proposed EPA and FLM Class I area SILs, no further modeling is required. The project was not expected to cause a significant impact to the air in the Class I area as shown in Table 11.

Since Amendment 3 addressed only an increase in PM₁₀ emissions which are minor (<30 tons per year) and the impacts analysis were below the recommended SILs, no visibility impact was required.

4.2. Other AQRVs

No deposition analysis was required for Amendment 3 because that application only addressed an increase in PM₁₀ emissions.

4.3. Construction and Growth Impacts

The proposed modification will not involve any new construction activities. Nor will it lead to an increase in the number of employees at the Ferndale Refinery. Therefore, no increase in

emissions from residential growth or in commuting-related mobile source emissions will be directly related to the proposed project. Therefore, the proposed project is not expected to cause adverse construction and growth-related impacts.

4.4. IMPACTS ON VEGETATION

The proposed project is not expected to have a significant impact on soils and vegetation from the proposed changes at the Ferndale Refinery.

5. CONCLUSION

The project will have no significant adverse impact on air quality. The Washington State Department of Ecology finds that the applicant, Phillips 66, has satisfied all requirements for PSD.

For additional information, please contact:

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